



**UNDERGROUND INJECTION CONTROL PROGRAM
PERMIT**

PREPARED: December 2011

Permit No. ND22184-08837

Class II Commercial Salt Water Disposal Well

**BIG BEND 1-5 SWD
Mountrail County, ND**

Issued To

Slawson Exploration CO, INC.

1675 Broadway, Suite 1600
Denver, CO 80202-4714

Part I. AUTHORIZATION TO CONSTRUCT AND OPERATE

Under the authority of the Safe Drinking Water Act and Underground Injection Control (UIC) Program regulations of the U. S. Environmental Protection Agency (EPA) codified at Title 40 of the Code of Federal Regulations (40 CFR) Parts 2, 124, 144, 146, and 147, and according to the terms of this Permit,

Slawson Exploration CO, INC.
1675 Broadway, Suite 1600
Denver, CO 80202-4714

is authorized to construct and to operate the following Class II injection well or wells:

BIG BEND 1-5 SWD
2500' FNL & 2400' FWL, SENW S5, T151N, R92W
Mountrail County, ND

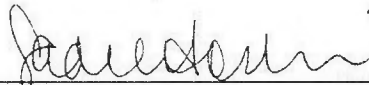
EPA regulates the injection of fluids into injection wells so that injection does not endanger underground sources of drinking water (USDWs). EPA UIC Permit conditions are based on authorities set forth at 40 CFR Parts 144 and 146, and address potential impacts to USDWs.

Under 40 CFR Part 144, Subpart D, certain conditions apply to all UIC Permits and may be incorporated either expressly or by reference. General permit conditions for which the content is mandatory and not subject to site-specific differences are not discussed in this document. Issuance of this Permit does not convey any property rights of any sort or any exclusive privilege, nor does it authorize injury to persons or property or invasion of other private rights, or any infringement of other Federal, State or local laws or regulations. (40 CFR §144.35) An EPA UIC Permit may be issued for the operating life of the injection well or project unless terminated for reasonable cause under 40 CFR §144.39, 144.40 and 144.41, and may be reviewed at least once every five (5) years to determine if action is required under 40 CFR §144.36(a).

This Permit is issued for the life of the well(s) unless modified, revoked and reissued, or terminated under 40 CFR §144.39 or 144.40. This EPA Permit may be adopted, modified, revoked and reissued, or terminated if primary enforcement authority for a UIC Program is delegated to an Indian Tribe or State. Upon the effective date of delegation, reports, notifications, questions and other correspondence should be directed to the Indian Tribe or State Director.

Issue Date: 12/15/11

Effective Date 12/15/11



Stephen S. Tuber

for Assistant Regional Administrator*
Office of Partnerships and Regulatory Assistance

*NOTE: The person holding this title is referred to as the "Director" throughout this Permit.

PART II. SPECIFIC PERMIT CONDITIONS

Section A. WELL CONSTRUCTION REQUIREMENTS

These requirements represent the approved minimum construction standards for well casing and cement, injection tubing, and packer.

Details of the approved well construction plan are incorporated into this Permit as APPENDIX A. Changes to the approved plan that may occur during construction must be approved by the Director prior to being physically incorporated.

1. Casing and Cement.

The well or wells shall be cased and cemented to prevent the movement of fluids into or between underground sources of drinking water. The well casing and cement shall be designed for the life expectancy of the well and of the grade and size shown in APPENDIX A. Remedial cementing may be required if shown to be inadequate by cement bond log or other attempted demonstration of Part II (External) mechanical integrity.

2. Injection Tubing and Packer.

Injection tubing is required, and shall be run and set with a packer at or below the depth indicated in APPENDIX A. The packer setting depth may be changed provided it remains below the depth indicated in APPENDIX A and the Permittee provides notice and obtains the Director's approval for the change.

3. Sampling and Monitoring Devices.

The Permittee shall install and maintain in good operating condition:

- (a) a "tap" at a conveniently accessible location on the injection flow line between the pump house or storage tanks and the injection well, isolated by shut-off valves, for collection of representative samples of the injected fluid; and
- (b) one-half (1/2) inch female iron pipe fitting, isolated by shut-off valves and located at the wellhead at a conveniently accessible location, for the attachment of a pressure gauge capable of monitoring pressures ranging from normal operating pressures up to the Maximum Allowable Injection Pressure specified in APPENDIX C:
 - (i) on the injection tubing; and
 - (ii) on the tubing-casing annulus (TCA); and
- (c) a pressure actuated shut-off device attached to the injection flow line set to shut-off the injection pump when or before the Maximum Allowable Injection Pressure (MAIP) specified in APPENDIX C is reached at the wellhead; and
- (d) a non-resettable cumulative volume recorder attached to the injection line.

4. Well Logging and Testing

Well logging and testing requirements are found in APPENDIX B. The Permittee shall ensure the log and test requirements are performed within the time frames specified in APPENDIX B. Well logs and tests shall be performed according to current EPA-approved procedures. Well log and test results shall be submitted to the Director within sixty (60) days of completion of the logging or testing activity, and shall include a report describing the methods used during logging or testing and an interpretation of the test or log results.

Injectate samples will be analyzed for Chlorides, Sulfates, Sulfides, Alkalinity, Total Dissolved Solids, Specific Gravity, Specific Conductivity, Trace Metals, NORM, TPH-DRO, TPH-GRO, Volatile Organic Compounds (including BTEX), Semi Volatile Compounds, and Non-Halogenated Alcohol (including methanol).

The preferred analytical methods are:

1. Method 8260 for Volatile Organic Compounds (Full Target Compound List and Tentatively Identified Compounds)
2. Method 8270 for Semi Volatile Organic Compounds (Full Target Compound List and Tentatively Identified Compounds)
3. Method 8015 for Non-Halogenated Alcohols (list of individual compounds to include Methanol)
4. Method 8270 or 8015 for TPH - DRO and TPH - GRO
5. Method E900.0 for Gross Alpha, Gross Beta
6. Method E903.0 for Radium 226, Total
7. Method RA-05 for Radium 228, Total

The Norm and Trace Metals samples will be collected at (5) wells: (2) Three Forks producers and (3) Bakken producers. This is a one time sample. The sample sites are:

Name	Formation	Location	Date on line
Skybolt 1-24H	Bakken	S24-T152N-R93W	12/30/09
Pathfinder 1-9H	Bakken	S9-T152N-R91W	7/24/08
Water Moccasin 4-34H	Three Forks	S34-T151N-R92W	4/17/11
Diamondback 1-21H	Bakken	S21-T151N-R92W	8/21/10
Jericho 2-5HTF	Three Forks	S5-T151N-R92W	5/25/10

Two samples to analyze for TPH-DRO, TPH-GRO, Volatile Organic Compounds (including BTEX), Semi Volatile Compounds, and Non-Halogenated Alcohol (including methanol) will be collected to analyze the 'evolution' of the produced water. These samples will be collected at (2) wells: Water Moccasin 4-34H (Three Forks Producer) and Diamondback 1-21H (Bakken Producer). A produced water sample will be collected at the separator. Another sample will be collected at the injection well. These samples will be collected prior to authorization to commence injection and then annually for three years thereafter.

After three years, only the sample collected at the injection well will continue to be collected annually for the life of the well. These samples will be analyzed for Chlorides, Sulfates, Sulfides, Alkalinity, Total Dissolved Solids, Specific Gravity, Specific Conductivity, Method

8260, 8270, and Trace Metals listed in Appendix B.

5. *Postponement of Construction or Conversion*

The Permittee shall complete well construction within one year of the Effective Date of the Permit, or in the case of an Area Permit within one year of Authorization of the additional well. Authorization to construct and operate shall expire if the well has not been constructed within one year of the Effective Date of the Permit or Authorization and the Permit may be terminated under 40 CFR 144.40, unless the Permittee has notified the Director and requested an extension prior to expiration. Notification shall be in writing, and shall state the reasons for the delay and provide an estimated completion date. Once Authorization has expired under this part, the complete permit process including opportunity for public comment may be required before Authorization to construct and operate may be reissued.

6. *Workovers and Alterations*

Workovers and alterations shall meet all conditions of the Permit. Prior to beginning any addition or physical alteration to an injection well that may significantly affect the tubing, packer or casing, the Permittee shall give advance notice to the Director and obtain the Director's approval. The Permittee shall record all changes to well construction on a Well Rework Record (EPA Form 7520-12), and shall provide this and any other record of well workover, logging, or test data to EPA within sixty (60) days of completion of the activity.

A successful demonstration of Part I MI is required following the completion of any well workover or alteration which affects the casing, tubing, or packer. Injection operations shall not be resumed until the well has successfully demonstrated mechanical integrity and the Director has provided written approval to resume injection.

Section B. MECHANICAL INTEGRITY

The Permittee is required to ensure each injection well maintains mechanical integrity at all times. The Director, by written notice, may require the Permittee to comply with a schedule describing when mechanical integrity demonstrations shall be made.

An injection well has mechanical integrity if:

- (a) There is no significant leak in the casing, tubing, or packer (Part I); and
- (b) There is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore (Part II).

1. Demonstration of Mechanical Integrity (MI).

The operator shall demonstrate MI prior to commencing injection and periodically thereafter. Well-specific conditions dictate the methods and the frequency for demonstrating MI and are discussed in the Statement of Basis. The logs and tests are designed to demonstrate both internal (Part I) and external (Part II) MI as described above. The conditions present at this well site warrant the methods and frequency required in Appendix B of this Permit.

In addition to these regularly scheduled demonstrations of MI, the operator shall demonstrate internal (Part I) MI after any workover which affects the tubing, packer or casing.

The Director may require additional or alternative tests if the results presented by the operator are not satisfactory to the Director to demonstrate there is no movement of fluid into or between USDWs resulting from injection activity. Results of MI tests shall be submitted to the Director as soon as possible but no later than sixty (60) days after the test is complete.

2. Mechanical Integrity Test Methods and Criteria

EPA-approved methods shall be used to demonstrate mechanical integrity. Ground Water Section Guidance No. 34 "Cement Bond Logging Techniques and Interpretation", Ground Water Section Guidance No. 37, "Demonstrating Part II (External) Mechanical Integrity for a Class II injection well permit", and Ground Water Section Guidance No. 39, "Pressure Testing Injection Wells for Part I (Internal) Mechanical Integrity" are available from EPA and will be provided upon request.

The Director may stipulate specific test methods and criteria best suited for a specific well construction and injection operation.

3. Notification Prior to Testing.

The Permittee shall notify the Director at least seven calendar days prior to any mechanical integrity test unless the mechanical integrity test is conducted after a well construction, well conversion, or a well rework, in which case any prior notice is sufficient. The Director may allow a shorter notification period if it would be sufficient to enable EPA to witness the mechanical integrity test. Notification may be in the form of a yearly or quarterly schedule of planned mechanical integrity tests, or it may be on an individual basis.

4. Loss of Mechanical Integrity.

If the well fails to demonstrate mechanical integrity during a test, or a loss of mechanical integrity becomes evident during operation (such as presence of pressure in the TCA, water flowing at the surface, etc.), the Permittee shall notify the Director within 24 hours (see Part III Section E Paragraph 11(e) of this Permit) and the well shall be shut-in within 48 hours unless the Director requires immediate shut-in.

Within five days, the Permittee shall submit a follow-up written report that documents test results, repairs undertaken or a proposed remedial action plan.

Injection operations shall not be resumed until after the well has successfully been repaired and demonstrated mechanical integrity, and the Director has provided approval to resume injection.

Section C. WELL OPERATION

INJECTION BETWEEN THE OUTERMOST CASING PROTECTING UNDERGROUND SOURCES OF DRINKING WATER AND THE WELL BORE IS PROHIBITED.

Injection is approved under the following conditions:

1. Requirements Prior to Commencing Injection.

Well injection, including for new wells authorized by an Area Permit under 40 CFR 144.33 (c), may commence only after all well construction and pre-injection requirements herein have been met and approved. The Permittee may not commence injection until construction is complete, and

- (a) The Permittee has submitted to the Director a notice of completion of construction and a completed EPA Form 7520-10 or 7520-12; all applicable logging and testing requirements of this Permit (see APPENDIX B) have been fulfilled and the records submitted to the Director; mechanical integrity pursuant to 40 CFR 146.8 and Part II Section B of this Permit has been demonstrated; and
 - (i) The Director has inspected or otherwise reviewed the new injection well and finds it is in compliance with the conditions of the Permit; or
 - (ii) The Permittee has not received notice from the Director of his or her intent to inspect or otherwise review the new injection well within 13 days of the date of the notice in Paragraph 1a, in which case prior inspection or review is waived and the Permittee may commence injection.

2. Injection Interval.

Injection is permitted only within the approved injection interval, listed in APPENDIX C. Additional individual injection perforations may be added provided that they remain within the approved injection interval and the Permittee provides notice to the Director in accordance with Part II, Section A, Paragraph 6.

3. Injection Pressure Limitation

- (a) The permitted Maximum Allowable Injection Pressure (MAIP), measured at the wellhead, is found in APPENDIX C. Injection pressure shall not exceed the amount the Director determines is appropriate to ensure that injection does not initiate new fractures or propagate existing fractures in the confining zone adjacent to USDWs. In no case shall injection pressure cause the movement of injection or formation fluids into a USDW.
- (b) The Permittee may request a change of the MAIP, or the MAIP may be increased or decreased by the Director in order to ensure that the requirements in Paragraph (a) above are fulfilled. The Permittee may be required to conduct a step rate injection test or other suitable test to provide information for determining the fracture pressure of the injection zone. Change of the permitted MAIP by the Director shall be by modification of this Permit and APPENDIX C.

4. Injection Volume Limitation.

Injection volume is limited to the total volume specified in APPENDIX C.

5. Injection Fluid Limitation.

Injected fluids are limited to those which are brought to the surface in connection with conventional oil or natural gas production and may be commingled with waste waters from gas plants which are an integral part of production operations unless those waters are classified as a hazardous waste at the time of injection, pursuant to 40 CFR 144.6(b). The Permittee shall provide an annual listing of sources of injected fluids in accordance with the reporting requirements in Part II Section D Paragraph 4 and APPENDIX D of this Permit.

- (a) The well may be used to inject Class II wastes brought to the surface such as drilling fluids and spent well completion, treatment and stimulation fluids. Non-exempt wastes, including unused fracturing fluids or acids, gas plant cooling tower cleaning wastes, service wastes and vacuum truck wastes, are NOT approved.
- (b) Initially, the well is permitted to accept fluid from the following sources:

Specific well information is on file at the US EPA Region 8 Office and is available upon request. Sources will be from the following fields: Square Butte, Whiskey Joe, Bicentennial, Squaw Gap, Mondak, Eagle Nest, Wildcat, Parshall, Van Hook, Big Bend, Ragged Butte, Elk, Sanish, Painted Woods, Alger, Ross, Kittleson Slough, and Kimberly.

A random representative sample of the injection water will be collected 30 days after injection commences and every other year thereafter at the sampling tap as described in the permit under Part II Sec.A.3.(a). The sample will be analyzed for NORM, TPH-DRO, TPH-GRO, BTEX, Volatile Organic Compounds, Semi Volatile Compounds, and Non-Halogenated Alcohol including methanol.

- (c) Additional sources of fluids may be accepted, provided that they meet the requirements listed in Paragraphs 5 and 5(a) above. Within thirty (30) days after accepting fluid from a new source, the Permittee shall:
 - (i) notify the Director, in writing, identifying the new source by well name(s), field name(s), or facility name(s); and.
 - (ii) submit a fluid analysis for the additional fluids to the Director. The fluid shall be analyzed for TDS, Specific Gravity, Specific Conductivity, and pH.

6. Tubing-Casing Annulus (TCA)

The tubing-casing annulus (TCA) shall be filled with water treated with a corrosion inhibitor, or other fluid approved by the Director. The TCA valve shall remain closed during normal operating conditions and the TCA pressure shall be maintained at zero (0) psi.

If TCA pressure cannot be maintained at zero (0) psi, the Permittee shall follow the procedures in Ground Water Section Guidance No. 35 "Procedures to follow when excessive annular pressure is observed on a well."

Section D. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. Monitoring Parameters, Frequency, Records and Reports.

Monitoring parameters are specified in APPENDIX D. Pressure monitoring recordings shall be taken at the wellhead. The listed parameters are to be monitored, recorded and reported at the frequency indicated in APPENDIX D even during periods when the well is not operating.

Monitoring records must include:

- (a) the date, time, exact place and the results of the observation, sampling, measurement, or analysis, and;
- (b) the name of the individual(s) who performed the observation, sampling, measurement, or analysis, and;
- (c) the analytical techniques or methods used for analysis.

2. Monitoring Methods.

- (a) Monitoring observations, measurements, samples, etc. taken for the purpose of complying with these requirements shall be representative of the activity or condition being monitored.
- (b) Methods used to monitor the nature of the injected fluids must comply with analytical methods cited and described in Table 1 of 40 CFR 136.3 or Appendix III of 40 CFR 261, or by other methods that have been approved in writing by the Director.
- (c) Injection pressure, annulus pressure, injection rate, and cumulative injected volumes shall be observed and recorded at the wellhead under normal operating conditions, and all parameters shall be observed simultaneously to provide a clear depiction of well operation.
- (d) Pressures are to be measured in pounds per square inch (psi).
- (e) Fluid volumes are to be measured in standard oil field barrels (bbl).
- (f) Fluid rates are to be measured in barrels per day (bbl/day).

3. Records Retention.

- (a) Records of calibration and maintenance, and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit shall be retained for a period of AT LEAST THREE (3) YEARS from the date of the sample, measurement, report, or application. This period may be extended anytime prior to its expiration by request of the Director.

- (b) Records of the nature and composition of all injected fluids must be retained until three (3) years after the completion of any plugging and abandonment (P&A) procedures specified under 40 CFR 144.52(a)(6) or under Part 146 Subpart G, as appropriate. The Director may require the Permittee to deliver the records to the Director at the conclusion of the retention period. The Permittee shall continue to retain the records after the three (3) year retention period unless the Permittee delivers the records to the Director or obtains written approval from the Director to discard the records.

4. Annual Reports.

Whether the well is operating or not, the Permittee shall submit an Annual Report to the Director that summarizes the results of the monitoring required by Part II Section D and APPENDIX D. The report of all sources of the fluids injected during the year must identify each source by the generator's name and the well name and location, and the field name or facility name.

The first Annual Report shall cover the period from the effective date of the Permit through December 31 of that year. Subsequent Annual Reports shall cover the period from January 1 through December 31 of the reporting year. Annual Reports shall be submitted by February 15 of the year following data collection. EPA Form 7520-11 may be copied and shall be used to submit the Annual Report, however, the monitoring requirements specified in this Permit are mandatory even if EPA Form 7520-11 indicates otherwise.

Section E. PLUGGING AND ABANDONMENT

1. Notification of Well Abandonment, Conversion or Closure.

The Permittee shall notify the Director in writing at least forty-five (45) days prior to: 1) plugging and abandoning an injection well, 2) converting to a non-injection well, and 3) in the case of an Area Permit, before closure of the project.

2. Well Plugging Requirements

Prior to abandonment, the injection well shall be plugged with cement in a manner which isolates the injection zone and prevents the movement of fluids into or between underground sources of drinking water, and in accordance with 40 CFR 146.10 and other applicable Federal, State or local law or regulations. Tubing, packer and other downhole apparatus shall be removed. Cement with additives such as accelerators and retarders that control or enhance cement properties may be used for plugs; however, volume-extending additives and gel cements are not approved for plug use. Plug placement shall be verified by tagging. Plugging gel of at least 9.2 lb/gal shall be placed between all plugs. A minimum 50 ft surface plug shall be set inside and outside of the surface casing to seal pathways for fluid migration into the subsurface. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation. Prior to placement of the cement plug(s) the well shall be in a state of static equilibrium with the mud weight equalized top to bottom, either by circulating the mud in the well at least once or by a comparable method prescribed by the Director.

3. Approved Plugging and Abandonment Plan.

The approved plugging and abandonment plan is incorporated into this Permit as APPENDIX E. Changes to the approved plugging and abandonment plan must be approved by the Director prior to beginning plugging operations. The Director also may require revision of the approved plugging and abandonment plan at any time prior to plugging the well.

4. Forty Five (45) Day Notice of Plugging and Abandonment.

The Permittee shall notify the Director at least forty-five (45) days prior to plugging and abandoning a well and provide notice of any anticipated change to the approved plugging and abandonment plan.

5. Plugging and Abandonment Report.

Within sixty (60) days after plugging a well, the Permittee shall submit a report (EPA Form 7520-13) to the Director. The plugging report shall be certified as accurate by the person who performed the plugging operation. Such report shall consist of either:

- (a) A statement that the well was plugged in accordance with the approved plugging and abandonment plan; or
- (b) Where actual plugging differed from the approved plugging and abandonment plan, an updated version of the plan, on the form supplied by the Director, specifying the differences.

6. Inactive Wells.

After any period of two years during which there is no injection the Permittee shall plug and abandon the well in accordance with Part II Section E Paragraph 2 of this Permit unless the Permittee:

- (a) Provides written notice to the Director;
- (b) Describes the actions or procedures the Permittee will take to ensure that the well will not endanger USDWs during the period of inactivity. These actions and procedures shall include compliance with mechanical integrity demonstration, Financial Responsibility and all other permit requirements designed to protect USDWs; and
- (c) Receives written notice by the Director temporarily waiving plugging and abandonment requirements.

PART III. CONDITIONS APPLICABLE TO ALL PERMITS

Section A. EFFECT OF PERMIT

The Permittee is allowed to engage in underground injection in accordance with the conditions of this Permit. The Permittee shall not construct, operate, maintain, convert, plug, abandon, or conduct any other activity in a manner that allows the movement of fluid containing any contaminant into underground sources of drinking water, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR 142 or may otherwise adversely affect the health of persons. Any underground injection activity not authorized by this Permit or by rule is prohibited. Issuance of this Permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of any other Federal, State or local law or regulations. Compliance with the terms of this Permit does not constitute a defense to any enforcement action brought under the provisions of Section 1431 of the Safe Drinking Water Act (SDWA) or any other law governing protection of public health or the environment, for any imminent and substantial endangerment to human health or the environment, nor does it serve as a shield to the Permittee's independent obligation to comply with all UIC regulations. Nothing in this Permit relieves the Permittee of any duties under applicable regulations.

Section B. CHANGES TO PERMIT CONDITIONS

1. *Modification, Reissuance, or Termination.*

The Director may, for cause or upon a request from the Permittee, modify, revoke and reissue, or terminate this Permit in accordance with 40 CFR 124.5, 144.12, 144.39, and 144.40. Also, this Permit is subject to minor modification for causes as specified in 40 CFR 144.41. The filing of a request for modification, revocation and reissuance, termination, or the notification of planned changes or anticipated noncompliance on the part of the Permittee does not stay the applicability or enforceability of any condition of this Permit.

2. *Conversions.*

The Director may, for cause or upon a written request from the Permittee, allow conversion of the well from a Class II injection well to a non-Class II well. Conversion may not proceed until the Permittee receives written approval from the Director. Conditions of such conversion may include but are not limited to, approval of the proposed well rework, follow up demonstration of mechanical integrity, well-specific monitoring and reporting following the conversion, and demonstration of practical use of the converted configuration.

3. *Transfer of Permit.*

Under 40 CFR 144.38, this Permit is transferable provided the current Permittee notifies the Director at least thirty (30) days in advance of the proposed transfer date (EPA Form 7520-7) and provides a written agreement between the existing and new Permittees containing a specific date for transfer of Permit responsibility, coverage and liability between them. The notice shall adequately demonstrate that the financial responsibility requirements of 40 CFR 144.52(a)(7) will be met by the new Permittee. The Director may require modification or revocation and reissuance of the Permit to change the name of the Permittee and incorporate such other requirements as may be necessary under the Safe Drinking Water Act; in some cases, modification or revocation and reissuance is mandatory.

4. Permittee Change of Address.

Upon the Permittee's change of address, or whenever the operator changes the address where monitoring records are kept, the Permittee must provide written notice to the Director within 30 days.

5. Construction Changes, Workovers, Logging and Testing Data

The Permittee shall give advance notice to the Director, and shall obtain the Director's written approval prior to any physical alterations or additions to the permitted facility. Alterations or workovers shall meet all conditions as set forth in this permit. The Permittee shall record any changes to the well construction on a Well Rework Record (EPA Form 7520-12), and shall provide this and any other record of well workovers, logging, or test data to EPA within sixty (60) days of completion of the activity.

Following the completion of any well workovers or alterations which affect the casing, tubing, or packer, a successful demonstration of mechanical integrity (Part III, Section F of this Permit) shall be made, and written authorization from the Director received, prior to resuming injection activities.

Section C. SEVERABILITY

The Provisions of this Permit are severable, and if any provision of this Permit or the application of any provision of this Permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this Permit shall not be affected thereby.

Section D. CONFIDENTIALITY

In accordance with 40 CFR Part 2 and 40 CFR 144.5, information submitted to EPA pursuant to this Permit may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be assessed in accordance with the procedures in 40 CFR Part 2 (Public Information). Claims of confidentiality for the following information will be denied:

- The name and address of the Permittee, and
- information which deals with the existence, absence or level of contaminants in drinking water.

Section E. GENERAL PERMIT REQUIREMENTS

1. Duty to Comply.

The Permittee must comply with all conditions of this Permit. Any noncompliance constitutes a violation of the Safe Drinking Water Act (SDWA) and is grounds for enforcement action; for Permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application; except that the Permittee need not comply with the provisions of this Permit to the extent and for the duration such noncompliance is authorized in an emergency permit under 40 CFR 144.34. All violations of the SDWA may subject the Permittee to penalties and/or criminal prosecution as specified in Section 1423 of the SDWA.

2. Duty to Reapply.

If the Permittee wishes to continue an activity regulated by this Permit after the expiration date of this Permit, under 40 CFR 144.37 the Permittee must apply for a new permit prior to the expiration date.

3. Need to Halt or Reduce Activity Not a Defense.

It shall not be a defense for a Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this Permit.

4. Duty to Mitigate.

The Permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this Permit.

5. Proper Operation and Maintenance.

The Permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the Permittee to achieve compliance with the conditions of this Permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this Permit.

6. Permit Actions.

This Permit may be modified, revoked and reissued or terminated for cause. The filing of a request by the Permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

7. Property Rights.

This Permit does not convey any property rights of any sort, or any exclusive privilege.

8. Duty to Provide Information.

The Permittee shall furnish to the Director, within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The Permittee shall also furnish to the Director, upon request, copies of records required to be kept by this Permit. The Permittee is required to submit any information required by this Permit or by the Director to the mailing address designated in writing by the Director.

9. Inspection and Entry.

The Permittee shall allow the Director, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

- (a) Enter upon the Permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of this Permit;

- (b) Have access to and copy, at reasonable times, any records that must be kept under the conditions of this Permit;
- (c) Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this Permit; and,
- (d) Sample or monitor at reasonable times, for the purpose of assuring permit compliance or as otherwise authorized by the SDWA, any substances or parameters at any location.

10. Signatory Requirements.

All applications, reports or other information submitted to the Director shall be signed and certified according to 40 CFR 144.32. This section explains the requirements for persons duly authorized to sign documents, and provides wording for required certification.

11. Reporting Requirements.

- (a) **Planned changes.** The Permittee shall give notice to the Director as soon as possible of any planned changes, physical alterations or additions to the permitted facility, and prior to commencing such changes.
- (b) **Anticipated noncompliance.** The Permittee shall give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.
- (c) **Monitoring Reports.** Monitoring results shall be reported at the intervals specified in this Permit.
- (d) **Compliance schedules.** Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this Permit shall be submitted no later than 30 days following each schedule date.
- (e) **Twenty-four hour reporting.** The Permittee shall report to the Director any noncompliance which may endanger human health or the environment, including:
 - (i) Any monitoring or other information which indicates that any contaminant may cause endangerment to a USDW; or
 - (ii) Any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs.

Information shall be provided, either directly or by leaving a message, within twenty-four (24) hours from the time the permittee becomes aware of the circumstances by telephoning (800) 227-8917 and requesting EPA Region VIII UIC Program Compliance and Technical Enforcement Director, or by contacting the EPA Region VIII Emergency Operations Center at (303) 293-1788.

In addition, a follow up written report shall be provided to the Director within five (5) days of the time the Permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause, the period of noncompliance including exact dates and times, and if the noncompliance has not been corrected the anticipated time it is expected to continue; and the steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

- (f) Oil Spill and Chemical Release Reporting: The Permittee shall comply with all reporting requirements related to the occurrence of oil spills and chemical releases by contacting the National Response Center (NRC) at (800) 424-8802, (202) 267-2675, or through the NRC website <http://www.nrc.uscg.mil/index.htm>.
- (g) Other Noncompliance. The Permittee shall report all instances of noncompliance not reported under paragraphs Part III, Section E Paragraph 11(b) or Section E, Paragraph 11(e) at the time the monitoring reports are submitted. The reports shall contain the information listed in Paragraph 11(e) of this Section.
- (h) Other information. Where the Permittee becomes aware that it failed to submit any relevant facts in the permit application, or submitted incorrect information in a permit application or in any report to the Director, the Permittee shall promptly submit such facts or information to the Director.

Section F. FINANCIAL RESPONSIBILITY

The operator has FR mechanism in place for \$75,000.

1. Method of Providing Financial Responsibility.

The Permittee shall maintain continuous compliance with the requirement to maintain financial responsibility and resources to close, plug, and abandon the underground injection well(s). No substitution of a demonstration of financial responsibility shall become effective until the Permittee receives written notification from the Director that the alternative demonstration of financial responsibility is acceptable. The Director may, on a periodic basis, require the holder of a permit to revise the estimate of the resources needed to plug and abandon the well to reflect changes in such costs and may require the Permittee to provide a revised demonstration of financial responsibility.

2. Insolvency.

In the event of:

- (a) the bankruptcy of the trustee or issuing institution of the financial mechanism; or

- (b) suspension or revocation of the authority of the trustee institution to act as trustee; or
- (c) the institution issuing the financial mechanism losing its authority to issue such an instrument

the Permittee must notify the Director in writing, within ten (10) business days, and the Permittee must establish other financial assurance or liability coverage acceptable to the Director within sixty (60) days after any event specified in (a), (b), or (c) above.

The Permittee must also notify the Director by certified mail of the commencement of voluntary or involuntary proceedings under Title 11 (Bankruptcy), U.S. Code naming the owner or operator as debtor, within ten (10) business days after the commencement of the proceeding. A guarantor, if named as debtor of a corporate guarantee, must make such a notification as required under the terms of the guarantee.

APPENDIX A

WELL CONSTRUCTION REQUIREMENTS

Schematic attached.

It is proposed to drill and complete the well as follows:

1. Build location, construct pit of 25' x 55' x 10' deep and insert 16 mil polyethylene liner.
2. Drill 13 1/2" hole to 150'+ below the Fox Hills to 1,863'+. At a minimum, a fresh water or air drilling system will be used to the base of USDWs.
3. Run drift surveys every 300'.
4. Run new 9 5/8" 36# K55 casing to 1,863'+. Cement in place with 400 sacks Control Set C (yield 2.66) and 357 sacks class G (yield 1.15). Use 60% excess and circulate cement to surface.
5. NU BOPE and test.
6. Drill 8 3/4" hole to projected TD of 5410'. Run drift surveys every 300'.
7. Run triple combo log suite, Gamma Ray, Induction and Neutron-density logs.
8. Run new 7" 23# N80 casing to TD. Cement in place with 405 sacks Litefill (yield 2.05) and 140 sacks Class G (yield 1.15). Cement volume calculated from caliper log plus 20% to surface.
9. Run CBL/CCL/GR log to 100' above top of cement.
10. Perforate Inyan Kara porosity intervals as determined from open hole logs (4845'-5261' gross interval). Collect injection zone water sample as described in Appendix G.
11. Run 3.5" 9.3# J55 tubing IPC TK70, with nickel coated on-off tool and 7" 23# nickel coated retrievable type packer with staging nipple below. Circulate fresh water inhibited packer fluid to annulus. Set packer and nipple up well head. Run MIT to 1000 PSIG for 15 minutes & notify NDIC and EPA for witnessing.
12. Clean up location, fill pit, and build surface facilities. (Note: The drill pit will not receive flowback water after stimulation or maintenance procedures or invert mud)

WELLHEAD EQUIPMENT:

- * Sampling tap located to enable sampling fluid in the injection tubing
- * Sampling tap located to enable sampling fluid in the tubing-casing annulus
- * Pressure gauge isolated by 1/2" FIP shut-off valve or quick-connect and located to enable reading the pressure on the injection tubing
- * Pressure gauge isolated by 1/2" FIP shut-off valve or quick-connect and located to enable reading the pressure on the tubing-casing annulus
- * Pressure actuated shut-off device located on the injection line, and set to prevent injection operations from exceeding the maximum allowable injection pressure
- * Non-resettable cumulative volume

No cores or drill stem tests are planned. Open and cased hole logs will be provided at the completion of the well as described in Appendix B. All depths are approximate.

A revised schematic and drill plan will be provided to the Director after completion.

2

NOV 11 1987

NOV 11 1987

NOV 11 1987





(Proposed)

WELLBORE DIAGRAM BIG BEND 1-5 SWD

GL ELEVATION = 1713.5'

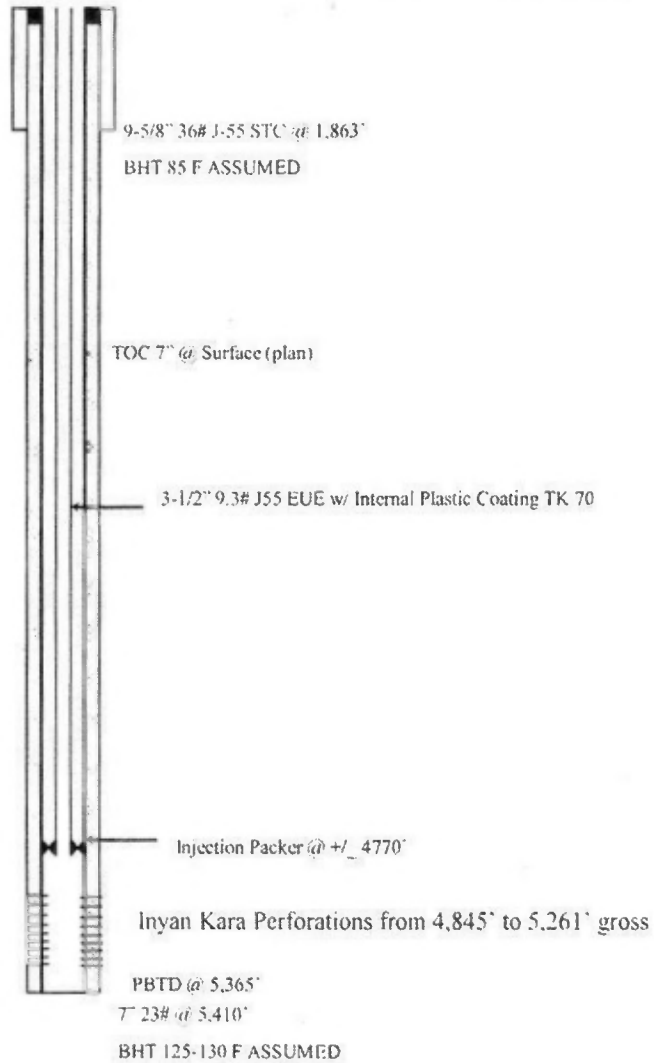
NE NW SEC 5 T151 R92
1/4 Sec 107 FNL and 2400' FWL
Mountrail County, North Dakota

USDW Surface-1713' < 10,000 TDS
Coleharbor-Fox Hills

Formation	TVD KB
Coleharbor Group	0-23'
Bullion Creek	23'
Cannon Ball	558'
Hell Creek	1,043'
Fox Hills	1,413'
Pierre	1,713'
Niobrara	3,587'
Carlile	3,855'
Greenhorn	4,085'
Belle Fourche	4,267'
Mowry	4,488'
Inyan Kara (Dakota)	4,845'
Swift	5,261'
TD	5,410'

Mowry Upper confining zone 4,488'

Swift Lower confining zone 5,261'



NOTE: NOT TO SCALE

String	Hole Size	Casing Size	Interval/Depth	CUFT	Yield	SXS	TOC
Surface Lead Set 'C'	13-1/2"	9-5/8"	0-1363'	1065	2.66	400	Surface
Surface Tail 500' G	60% Necess		1363-1863'	391	1.15	357	1363'
Production Lead 'Lite'	8-3/4"	7"	0-4600'	830	2.05	405	Surface
Production Tail 810' G	20% Necess		4600-5410'	148	1.15	140	4600'

UPDATED 7/28/14
JON LAYNE/dcs



GL ELEVATION = 1898'
KB ELEVATION = 1902'
API# 33-061-90195-00-00
NDIC: 90195

**WELLBORE DIAGRAM
BIG BEND 1-5 SWD**

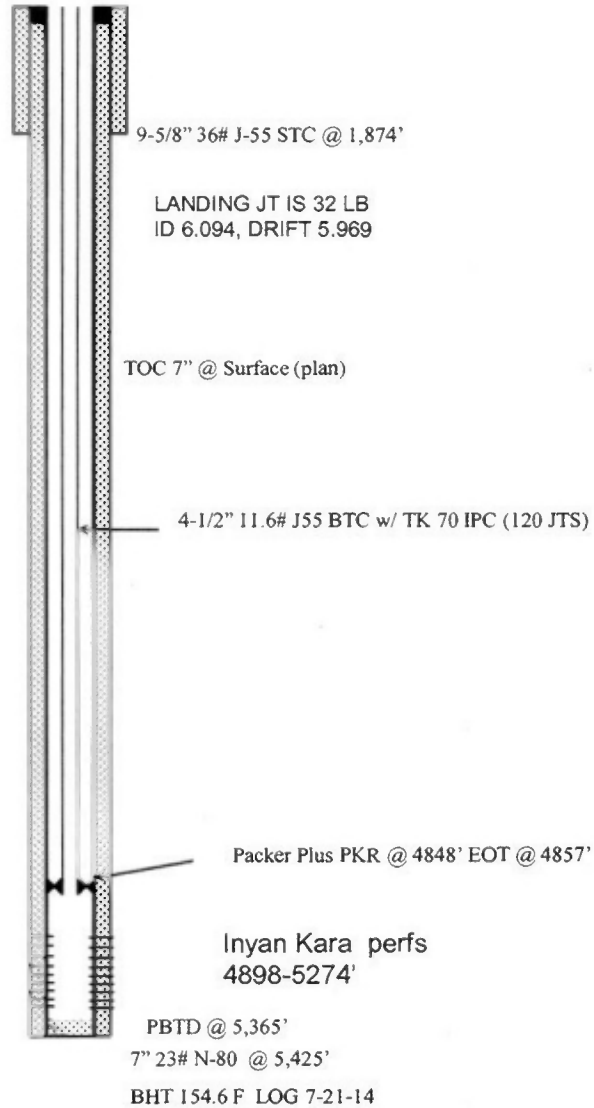
SE NW SEC 5 T151 R92
2500' FNL and 2400' FWL
Mountrail County, North Dakota

USDW Surface-1713' < 10,000 TDS
Coleharbor-Fox Hills

Formation	TVD KB
Coleharbor Group	0-23'
Bullion Creek	23'
Cannon Ball	558'
Hell Creek	1,043'
Fox Hills	1,413'
Pierre	1,705'
Niobrara	3,604'
Carlile	3,870'
Greenhorn	4,104'
Belle Fourche	4,292'
Mowry	4,503'
Inyan Kara (Dakota)	4,871'
Swift	5,274'
TD	5,444'
Mowry Upper confining assumed zone 4,503'	

Swift Lower confining zone 5,274'

NOTE: NOT TO SCALE



APPENDIX B

LOGGING AND TESTING REQUIREMENTS

Logs.

Logs will be conducted according to current UIC guidance. It is the responsibility of the Permittee to obtain and use guidance prior to conducting any well logging required as a condition of this permit.

A copy of EPA R6 Pressure Falloff Testing Guideline (Aug 8, 2002), EPA R8 Temperature Logging For Mechanical Integrity, EPA R8 Guideline: Radioactive Tracer Surveys for Evaluating Fluid Channeling Behind Casing near Injection Perforations was emailed to the operator (Don Smith) on 5/29/11.

WELL NAME: BIG BEND 1-5 SWD

TYPE OF LOG	DATE DUE
N-Density	Injection Well: Prior to receiving authorization to commence injection.
array induction/SP/MSFL	Injection Well: Prior to receiving authorization to commence injection.
CBL/VDL/GAMMA RAY	Injection Well: Prior to receiving authorization to commence injection. Operator will provide log and analysis of log data.
RATS	Injection Well: If CBL does not show adequate cement behind pipe. Baseline required and every 5 years thereafter. Operator will provide log and analysis of log data.
TEMP	Injection Well: A baseline required prior to injection. This log will serve as a baseline for all wells located in Sec 5-T151N-R92W. Operator will provide log and analysis of log data.

Tests.

Tests will be conducted according to current UIC guidance. It is the responsibility of the Permittee to obtain and use guidance prior to conducting any well test required as a condition of this permit.

If injectate samples analyzed for NORM exceeds EPA's drinking water MCLs, then the operator and EPA will collaborate to determine the need for a monitoring plan to better characterize any variability or exceedances.

WELL NAME: BIG BEND 1-5 SWD

TYPE OF TEST	DATE DUE
Pressure Fall-Off Test	Injection Well: Within 180 days after injection commences. Operator will provide analysis of test results and the test data.
Braden Head Pressure	Injection Well: Prior to authorization to commence injection and weekly thereafter. Pressure data to be collected from annulus on backside of production casing. Any variance from baseline will be investigated and reported to EPA in 36 hours.
Braden Head Pressure	Jericho 2-5H-TF, 1-5H, 3-5H; Coyote 1-32H, 2-32H; Hunter 2-8-17H : Baseline Braden Head Pressure and weekly monitoring required. Any variance from baseline will be investigated and reported to EPA within 36 hours.
Injectate Sample	Injection Well: 30 days after injection commences and annually thereafter. The produced water will be tested for chloride, sulfate, sulfide, alkalinity, TDS, specific gravity, specific conductivity, and pH.
*Braden Head Pressure	Wells requiring monitoring: Pressure data will be collected from the annulus on backside of production casing. Both baseline and weekly monitoring required. Any variances from baseline will be investigated and reported to EPA within 36 hours.
Step Rate Test	Injection Well: Prior to receiving authorization to commence injection. Operator will provide analysis of test results and raw data.
Injectate Sample	Injection Well: After 4 years of injection, a random sample will be collected and analyzed for Method 8260, 8270 (including TIC for both) and Trace Metals (list included with this Appendix).
Injection Zone Water Sample	Injection Well: Prior to receiving authorization to commence injection. Sample should be analyzed for geochemical parameters, including trace metals and TDS.
Injectate Sample	Injection Well: 30 days after injection commences and annually for (3) years. The sample will be analyzed under all 7 methods described in the Permit under the Well Logging and Testing section.
Isolated Injectate Sample	Skybolt 1-24H, Pathfinder 1-9H, Water Moccasin 4-34H, Diamond back 1-21H, Jericho 2-5HTF: Prior to receiving authorization to commence injection. The wells will be sampled once for NORM per sampling plan described in the Permit.
Isolated Injectate Sample	Skybolt 1-24H, Pathfinder 1-9H, Water Moccasin 4-34H, Diamond back 1-21H, Jericho 2-5HTF: Prior to receiving authorization to commence injection. The wells will be sampled once for Trace Metals per sampling plan described in the Permit.
Isolated Injectate Sample	Water Moccasin 4-34H and Diamondback 1-21H: Prior to receiving authorization to commence injection and annually for (3) years thereafter. The wells will be sampled for TPH-DRO and TPH-GRO per sampling plan described in the Permit.

Isolated Injectate Sample	Water Moccasin 4-34H and Diamondback 1-21H: Prior to receiving authorization to commence injection and annually for (3) years thereafter. The wells will be sampled for Volatile Organic Compounds per sampling plan described in the Permit.
Isolated Injectate Sample	Water Moccasin 4-34H and Diamondback 1-21H: Prior to receiving authorization to commence injection and annually for (3) years thereafter. The wells will be sampled for Semi Volatile Compounds per sampling plan described in the Permit.
Isolated Injectate Sample	Water Moccasin 4-34H and Diamondback 1-21H: Prior to receiving authorization to commence injection and annually for (3) years thereafter. The wells will be sampled for Non-Halogenated Alcohol per sampling plan described in the Permit.
Pore Pressure	Injection Well: Prior to receiving authorization to commence injection and at least once annually thereafter. Operator will provide analysis of results and data.

Trace Metals Analysis

(Analysis Information with Associated Analyte and MDL/MRL Information)

Analysis	Analyte	Matrix	MDL (ug/L)	MRL (ug/L)
ICP Tital Metals - R8	Boron	Water	15.0	100
ICP Tital Metals - R8	Calcium	Water	10.0	100
ICP Tital Metals - R8	Iron	Water	10.0	100
ICP Tital Metals - R8	Magnesium	Water	26.0	100
ICP Tital Metals - R8	Manganese	Water	0.4	2.0
ICP Tital Metals - R8	Potassium	Water	170	1000
ICP Tital Metals - R8	Silica	Water	50.0	200
ICP Tital Metals - R8	Sodium	Water	70.0	500
ICP Tital Metals - R8	Tin	Water	50.0	200
ICP Tital Metals - R8	Titanium	Water	1.8	10.0
ICP-MS total metals-R8	Aluminum	Water	4.0	20.0
ICP-MS total metals-R8	Antimony	Water	0.8	1.0
ICP-MS total metals-R8	Arsenic	Water	1.0	4.0
ICP-MS total metals-R8	Barium	Water	0.1	0.3
ICP-MS total metals-R8	Beryllium	Water	0.03	0.2
ICP-MS total metals-R8	Cadmium	Water	0.05	0.2
ICP-MS total metals-R8	Chromium	Water	1.0	5.0
ICP-MS total metals-R8	Cobalt	Water	0.01	0.1
ICP-MS total metals-R8	Copper	Water	4.0	10.0
ICP-MS total metals-R8	Lead	Water	0.2	1.0
ICP-MS total metals-R8	Molybdenum	Water	0.02	0.5
ICP-MS total metals-R8	Nickel	Water	0.1	1.0
ICP-MS total metals-R8	Selenium	Water	0.2	1.0
ICP-MS total metals-R8	Silver	Water	0.1	0.5
ICP-MS total metals-R8	Thallium	Water	0.01	0.3
ICP-MS total metals-R8	Thorium	Water	0.03	0.3
ICP-MS total metals-R8	Uranium	Water	0.006	0.1
ICP-MS total metals-R8	Vanadium	Water	2.0	10.0
ICP-MS total metals-R8	Zinc	Water	2.0	5.0

APPENDIX C

OPERATING REQUIREMENTS

MAXIMUM ALLOWABLE INJECTION PRESSURE:

Maximum Allowable Injection Pressure (MAIP) as measured at the surface shall not exceed the pressure(s) listed below.

WELL NAME	MAXIMUM ALLOWED INJECTION PRESSURE (psi)
	ZONE 1 (Upper)
BIG BEND 1-5 SWD	1,350

INJECTION INTERVAL(S):

Injection is permitted only within the approved injection interval listed below. Injection perforations may be altered provided they remain within the approved injection interval and the Permittee provides notice to the Director in accordance with Part II, Section A, Paragraph 6. Specific injection perforations can be found in Appendix A.

WELL NAME: BIG BEND 1-5 SWD			
FORMATION NAME	APPROVED INJECTION INTERVAL (KB, ft)		FRACTURE GRADIENT (psi/ft)
	TOP	BOTTOM	
Inyan Kara	4,845.00	5,274.00	0.800

ANNULUS PRESSURE:

The annulus pressure shall be maintained at zero (0) psi as measured at the wellhead. If this pressure cannot be maintained, the Permittee shall follow the procedures listed under Part II, Section C. 6. of this permit.

MAXIMUM INJECTION VOLUME:

WELL NAME: BIG BEND 1-5 SWD	
FORMATION NAME	MAXIMUM VOLUME LIMIT (bbls)
Inyan Kara	71,500,000.00

APPENDIX D

MONITORING AND REPORTING PARAMETERS

This is a listing of the parameters required to be observed, recorded, and reported. Refer to the permit Part II, Section D, for detailed requirements for observing, recording, and reporting these parameters.

OBSERVE WEEKLY AND RECORD AT LEAST ONCE EVERY THIRTY DAYS	
OBSERVE AND RECORD	Injection pressure (psig)
	Annulus pressure(s) (psig)
	Injection rate (bbl/day)
	Fluid volume injected since the well began injecting (bbls)
ANNUALLY	
ANALYZE	Injected fluid total dissolved solids (mg/l)
	Injected fluid specific gravity
	Injected fluid specific conductivity
	Injected fluid pH
ANNUALLY	
REPORT	Each month's maximum and averaged injection pressures (psig)
	Each month's maximum and minimum annulus pressure(s) (psig)
	Each month's injected volume (bbl)
	Fluid volume injected since the well began injecting (bbl)
	Written results of annual injected fluid analysis

In addition to these items, additional Logging and Testing results may be required periodically. For a list of those items and their due dates, please refer to APPENDIX B - LOGGING AND TESTING REQUIREMENTS.

APPENDIX E

PLUGGING AND ABANDONMENT REQUIREMENTS

Schematic attached.

The well shall be plugged in a manner that isolates the injection zone and prevents movement of fluid into or between USDWs and in accordance with other applicable Federal, State, or local law or regulation. Tubing, packers, and any downhole apparatus shall be removed. Class A, C, G, and H cements, with additives such as accelerators and retarders that control or enhance cement properties, may be used for plugs. However, volume extending additives and gel cements are not approved for plug use. Plug placement shall be verified by tagging. Plugging gel of at least 9.2 lb/gal shall be placed between all plugs. Within 60 days after plugging, the owner or operator shall submit Plugging Record (EPA Form 7520-13) to the Director. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation. At a minimum, the following plugs are required via the proposed P&A Plan below:

Big Bend 1-5 SWD
Proposed P&A Procedure

Perform Mechanical Integrity Test
Pull tubing and packer
Repair any casing leaks

Casing Program:
Surface Casing:
9 5/8" 36# K55 ST&C casing to 1863'.
Production Casing:
7" 23# N80 @ 5410' drifted to 6 1/8"
Production Tubing:
3 1/2" 9.3# J55 EUE w/ Internal plastic coat TK70

Special Instructions:
Always stay on established lease roads.

P&A Procedure:

The proposed design incorporates safety as well as efficiency into the plugging and abandonment of the SWD. At the termination of the well's useful life, the well most likely will be pressured up. This potentially could cause an unsafe working condition as working on live wells is always a dangerous proposition. Bleeding down the well would require the flowing back of injected water, counter productive to an already disposed fluid needing to be disposed of again. Also, it is not known how much time would be

required for bleed down to occur, or what total volume of previously injected fluid would be recovered and require disposal into another well. Killing the well with heavy mud is considered a poor method of containment as this could plug off the perfs/formation and not allow cement to be pumped into the well. The method proposed utilizes pressure containment equipment that will hold the pressure and the injected fluids at the formation, while allowing the surface pressure to be zero, and also allowing cement to be pumped into the well, thus ensuring a safe, reliable plugging method.

1. Move in P&A Rig.
2. Check well for pressure and set 3½" downhole blanking plug w/ bypass in nipple for pressure containment as necessary.
3. Nipple up BOPE.
4. Sting out from Permanent Packer at +/- 4770' at on/off tool. TOOH and lay down 3 ½" 9.3# J55 tubing.
5. Pick up 2 3/8" or 2 7/8" work string w/ sting and attach to Packer at on/off tool.
6. Pressure test annulus to 1000 PSI. Establish injection rate and pressure.
7. Plug #1. Mix and pump 115 sacks Class G. Squeeze perforations with 105 sacks below packer and spot 10 sacks on top. TOC at 4720' calculated.
8. Pull up 5 Stands and reverse tubing clean.
9. Role hole with 9.2 PPG inhibited brine to surface. TOOH.
10. Pickup 6 1/8" bit and 7" scraper and TIH to 1975'. TOOH.
11. TIH w/ tubing to 1963'.
12. Plug #2. Mix and spot 40 sacks Class G cement (2% Calcium Chloride optional) from 1963' to 1763'. WOC and tag with tubing. Record top plug depth.
13. TOOH and lay down tubing to 200'. Strip off BOPE.
14. Plug #3. Mix and spot 40 sacks Class G (2% Calcium Chloride optional) from 200' to surface. WOC.
15. Cut off well head 3' below ground level.
16. Weld on plate w/ weep hole and the following information: Slawson Expl. Co, Inc., Big Bend 1-5 SWD, NENW Sec 5-T151N-R92W.



**WELLBORE DIAGRAM
BIG BEND I-5 SWD
PROPOSED P&A**

GL ELEVATION = 1900.5' EST

KB ELEVATION = 1904.5' EST

API#

NE NW SEC 5 T151 R92
Sec 405 FNL and 2400' FWL
Mountrail County, North Dakota

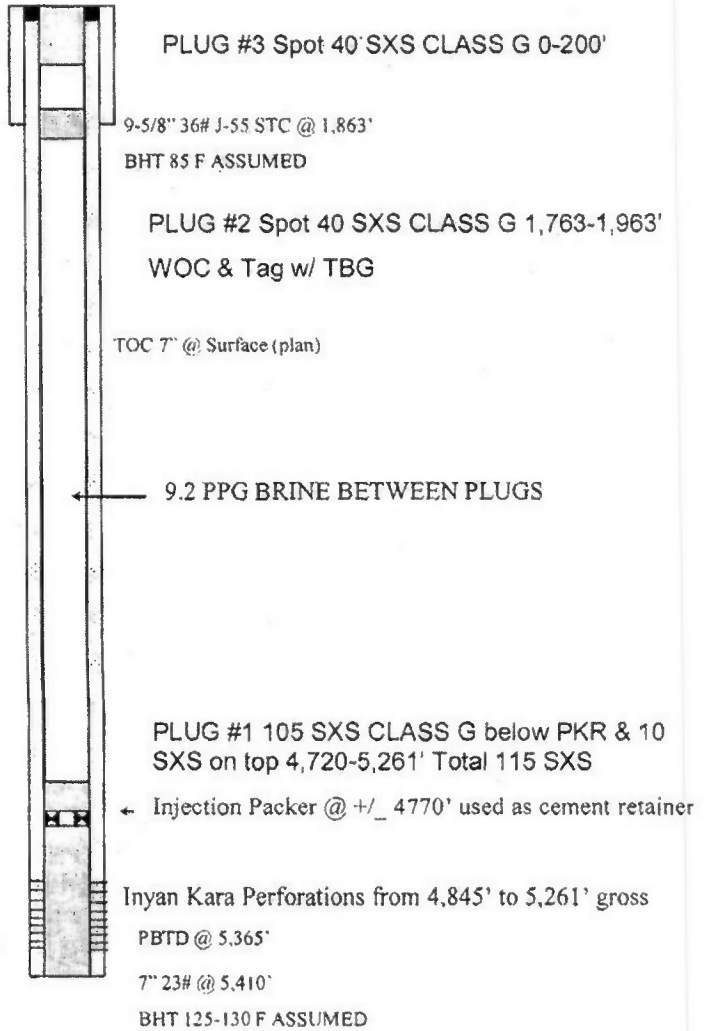
USDW Surface-1713' < 10,000 TDS

Coleharbor-Fox Hills

Formation	TVD
Coleharbor Group	0-23'
Bullion Creek	23'
Cannonball	558'
Hell Creek	1,043'
Fox Hills	1,413'
Pierre	1,713'
Niobrara	3,587'
Carlile	3,855'
Greenhorn	4,085'
Belle Fourche	4,267'
Mowry	4,488'
Inyan Kara (Dakota)	4,845'
Swift	5,261'
TD	5,410'

Mowry Upper confining zone 4,488'

Swift Lower confining zone 5,261'



NOTE: NOT TO SCALE

String	Hole Size	Casing Size	Interval/Depth	CUFT	Yield	SXS	TOC
Surface Lead Set 'C'	13-1/2"	9-5/8"	0-1400'	1065	2.66	400	Surface
Surface Tail 500' G			1363-1863'	391	1.15	357	1363'
Production Lead 'Lite'	8-3/4"	7"	0-4600'	830	2.05	405	Surface
Production Tail 820' G			4600-5410'	148	1.15	140	4600'

APPENDIX F

CORRECTIVE ACTION REQUIREMENTS

There are no wells within the 1/4 mile area of review, however there are six production wells located within 1/2 mile of the proposed injection well's location. The CBL analysis did not show adequate cement bonding behind pipe on any of the wells, therefore Braden Head monitoring is being required. The Braden Head for all of the wells: Jericho 2-5H-TF, Jericho 1-5H, Jericho 3-5H, Coyote 1-32H, Coyote 2-32H and Hunter 2-8-17H will be monitored on the backside of the production casing. Baseline data will be collected prior to authorization to commence injection and weekly thereafter. If any of these wells has a variance in pressure from what was measured during the baseline monitoring, the well will be investigated and reported to EPA within 36 hours. If the pressure increase is greater than 50 pounds, then injection will cease while investigation occurs. A baseline temperature log is being required on the Big Bend 1-5 SWD that will serve as a baseline for all wells located in Section 5, Township 151N Range 92W. A pressure fall off test is being required, if linear flow is discovered then testing requirements may be revised.

Any additional wells drilled in Section 5 will be reported to EPA for analysis upon completion. The operator will submit all drillers reports and logs within 30 days of completing the well. At a minimum a CBL will be submitted for analysis. If cement through the identified confining zone is found to be inadequate, additional testing in the form of RTS and temperature log may be required on the newly drilled well.

BIG BEND 1-5 SWD
PORE VOLUME CALCULATION
May 27, 2011

The attached PV calculation was obtained by the following method:

1. An analysis was made of the nearby Zenergy Dakota 3 Pennington 16-15H (SESE S15 T152N R92W) porosity log across the Dakota from 4903-5326'. Not all porosity intervals were included.
2. From the above log analysis, a calculation of average porosity was obtained and recorded as PHI= 25.64% over the 111' (H).
3. Using the standard Pore Volume equation: $PV = 7758 * PHI * AREA * H$ the displaced area was calculated based on the following assumptions: Avg Inj= 5000 BPD, H=111 Ft, PHI=25.64%.
4. The data shows the area displaced by year assuming piston like displacement and a 365 day year with no down time. The analysis of the data shows it will be approximately 50-55 years to reach the closest well (Jericho 2-5 TFH). This documentation is in EPA-Region 8's permit file under the technical review section.

UPDATE 2/24/10 DCS

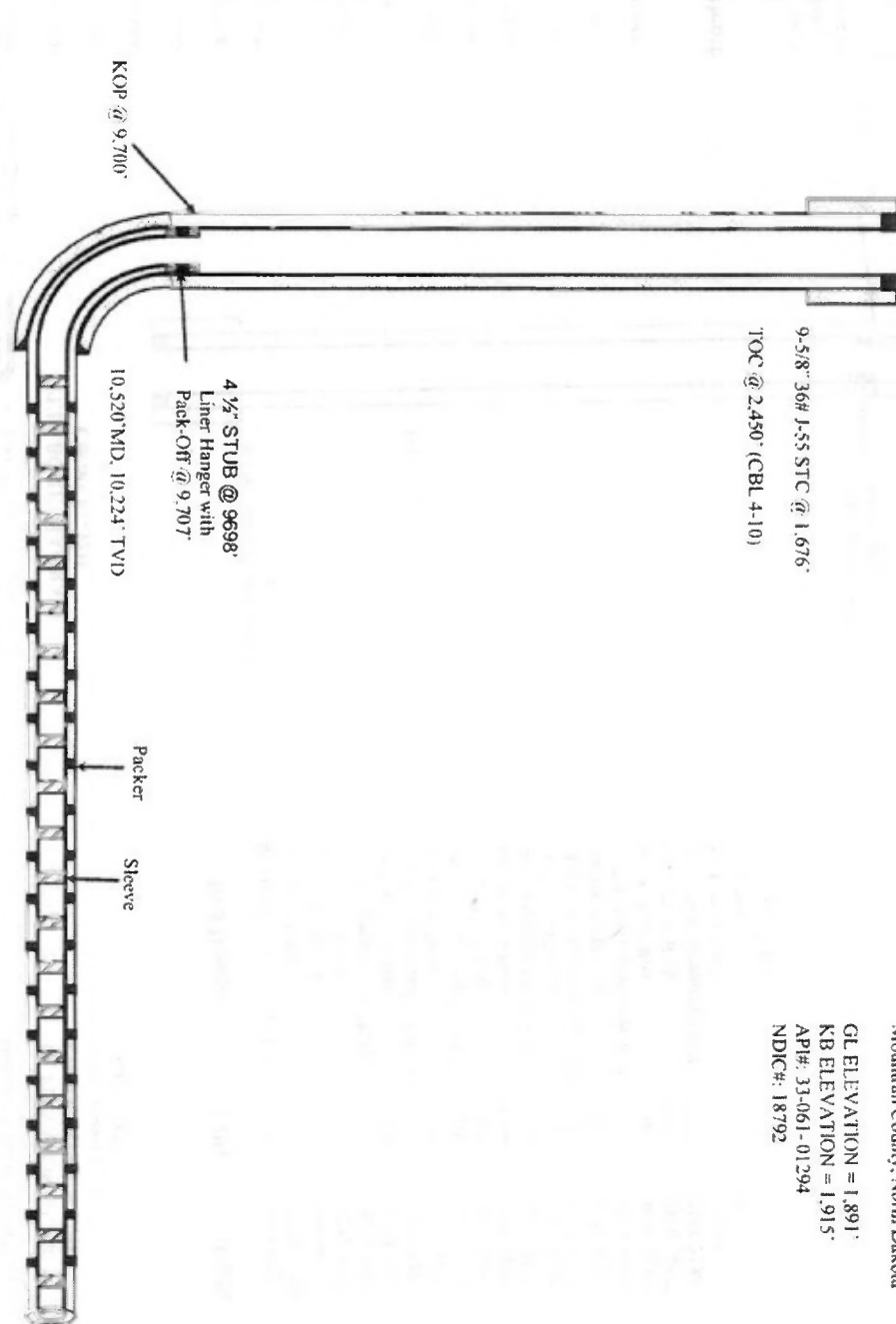


WELLBORE DIAGRAM
Jericho #2-STFH

Location: 310' FNL and 1,330' FEL.
NWNE Sec 5, T151N-R92W
Mountrail County, North Dakota

GL ELEVATION = 1,891'
KB ELEVATION = 1,915'
API#: 33-061-01294
NDIC#: 18792

Formation	TVD
Pierre base Foxhills	1,589'
Dakota (marine)	4,860'
Dunham Salt	Absent
Base Dunham Salt	Absent
Pine Salt	6,500'
Base Pine Salt	6,541'
Opeche	6,546'
Minnelusa	6,939'
Kibbey Lime	7,795'
Charles	7,962'
base last Charles salt	8,495'
Mission Canyon	8,672'
Lodgepole	9,288'
Upper Bakken shale	10,110'
Lower Bakken Shale	10,175'
Three Forks	10,218'
Top of Target	10,228'



7" 29# P-110 from Surface to 6,200'
7" 32# P-110 from 6,200' to 8,618'
7" 29# P-110 from 8,618' to 10,520'

4,722' of 4-1/2" 11.6# P-110
liner with 20 packers, 21 sleeves
and a liner hanger with pack-off
(578'). Set Liner at 14,429'

Lateral TD @ 14,460' MD.
10,230' TVD
3,940' of Open Hole

Formation	TVD
Pierre-base Foxhills	1,593'
Dakota (marine)	5,022'
Dunham Salt	6,384'
Base Dunham Salt	6,402'
Pine Salt	6,555'
Base Pine Salt	6,689'
Opeche	6,714'
Base Opeche	6,943'
Kibbey Lime	7,760'
Charles	7,982'
base last Charles salt	8,512'
Mission Canyon	8,682'
Lodgepole	9,284'
Upper Bakken shale	10,104'
Top of Target	10,130'
Target	10,135'
Base of Target	10,140'

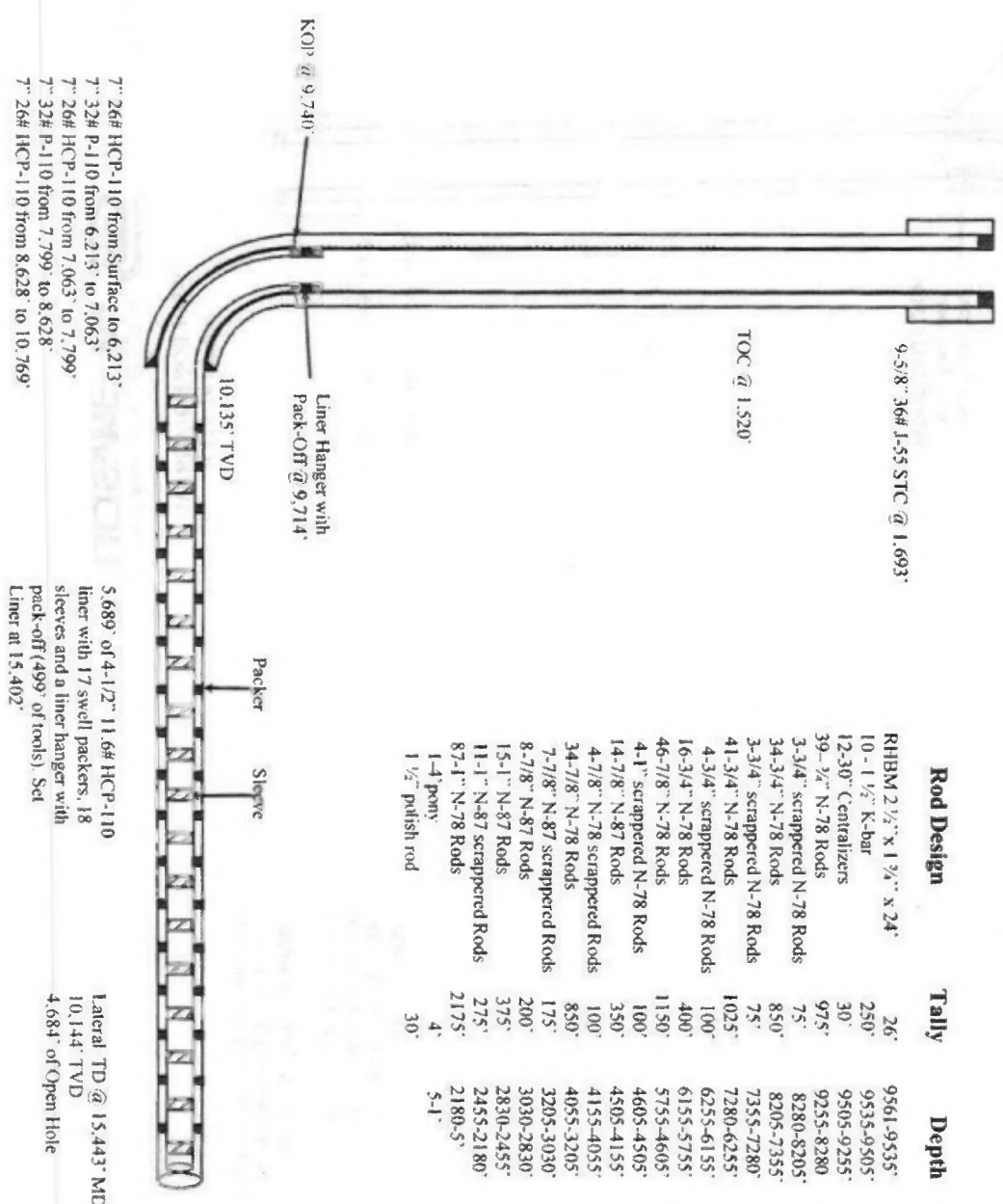
Up Dated 11-18-10
Gary Dorval



WELL BORE DIAGRAM
Coyote #1-32H

Location: 280' ENL and 1,630' FEL
NWNE Sec 32, T152N-R92W
Mountain County, North Dakota
GL ELEVATION = 1,894'
KB ELEVATION = 1,918'
API#: 33-061-01082
NDIC#: 18220

Tubing Profile	Tally	Depth
KB	24.00	
306 JTS 2 7/8 6.5# L-80 EUE	9536.55	9560.55
Cup Type SN	1.10	9561.65
Carbide TAC	2.35	9564.00
2 JT 2 7/8"	62.13	9526.13
Echo gas anchor	5.10	9631.23
1 JT 2 7/8" bullplugged	31.82	9663.05



Rod Design	Tally	Depth
RHBM 2 1/2" x 1 3/4" x 24'	26'	9561-9535'
10 - 1 1/2" K-bar	250'	9535-9505'
12-30" Centralizers	30'	9505-9255'
39- 3/4" N-78 Rods	975'	9255-8280'
3-3/4" scrapped N-78 Rods	75'	8280-8205'
34-3/4" N-78 Rods	850'	8205-7355'
3-3/4" scrapped N-78 Rods	75'	7355-7280'
41-3/4" N-78 Rods	1025'	7280-6255'
4-3/4" scrapped N-78 Rods	100'	6255-6155'
16-3/4" N-78 Rods	400'	6155-5755'
46-7/8" N-78 Rods	1150'	5755-4605'
4-1" scrapped N-78 Rods	100'	4605-4505'
14-7/8" N-87 Rods	350'	4505-4155'
4-7/8" N-78 scrapped Rods	100'	4155-4055'
34-7/8" N-78 Rods	850'	4055-3205'
7-7/8" N-87 scrapped Rods	175'	3205-3030'
8-7/8" N-87 Rods	200'	3030-2830'
15-1" N-87 Rods	375'	2830-2455'
11-1" N-87 scrapped Rods	275'	2455-2180'
87-1" N-78 Rods	2175'	2180-5'
1-4" pony	4'	
1 1/2" polished rod	30'	

7" 26# HCP-110 from Surface to 6,213'
 7" 32# P-110 from 6,213' to 7,063'
 7" 26# HCP-110 from 7,063' to 7,799'
 7" 32# P-110 from 7,799' to 8,628'
 7" 26# HCP-110 from 8,628' to 10,769'

5,689' of 4-1/2" 11.6# HCP-110
 liner with 17 swell packers, 18
 sleeves and a liner hanger with
 pack-off (499' of tools) Set
 Liner at 15,402'

Lateral TD @ 15,443' MID.
 10,144' TVD
 4,684' of Open Hole

APPENDIX G

INJECTION ZONE WATER SAMPLING FOR SWD WELLS

Data Quality Objectives

To sufficiently purge the well and obtain a representative sample of the injection zone formation water to determine:

- whether injection zone is a underground source of drinking water (USDW, TDS<10,000 mg/L)

Well Preparation and Sampling Procedure

1. MIRU Workover rig
2. **IF** workover fluid has been pumped into the well for corrective action requirements (i.e. squeeze work, RAT's test, etc) near the proposed injection interval, get an accurate record of the volume pumped to account for and also obtain a sample of the workover fluid for reference purposes.
3. RIH with tubing to the \pm top of the injection interval. Rig up swab equipment and swab the fluid level to 500' above injection zone interval so the well can be perforated under-balanced.
4. POOH with the tubing
5. RIH and under-balance perforate the proposed injection interval with the appropriate sized guns. POOH with the perforating guns.
6. Define parameter in mud system that can be easily monitored for (e.g. barium)
7. RIH with tubing to the \pm top of the injection interval
 - a. **IF** a pore pressure measurement is required, conduct using down hole pressure tools via wireline OR some other pre-approved method.
 - b. POOH with the pressure tools.
8. R/U to swab or foam the well to get a representative fluid sample of the injection interval. **NOTE: It may be necessary to break-down and/or acidize the perforations in order obtain adequate fluid entry into the wellbore.**
 - a. Take regular samples and monitor chlorides, potassium, and pH of the water.
 - b. Document field readings of Load Water Volume to Recover, Time, Volume of Fluid Recovered, Conductivity, pH, Chlorides, and Potassium during the entire field sampling process (see attached table).

NOTE: Sampling frequency depends on how much volume needs to be recovered. The objective is to obtain three stabilized samples after a minimum of twice the volume of load is recovered.
 - c. Continue swabbing or air lifting the well until all fluid that has been put into the well from corrective action operations has been accounted for.
 - d. Once the chlorides, potassium, and pH have stabilized (see table) and look to be representative of the injection zone interval, take three last successive samples (plus selected previous samples for comparisons) in for complete water analysis to measure for mud parameter, TDS, pH, SG, and conductivity.
 - e. **IF** laboratory analysis shows inconsistent results, zone will need to be resampled.

Perforated Interval (ft bgs) _____ Total Load Water Volume (bbbls) _____

[illegible]

APPENDIX H

SITE SERCURITY

Permittee will install and maintain in continuous working order a "one month" pressure recording chart (or digital hard drive equipment) on the well head, where it will continuously measure the surface injection pressure for the well during all times. The chart will be changed monthly by the Permittee and the charts (or hard drive data) will be retained in the Permittee's offices for reference and reporting purposes for a minimum of 5 years.

Signage

The facilities will have signage indicating that the property is private and no trespassing is allowed. Signs will be posted at the entrance from public roads.

Gates and Fences

The perimeter of the site will be fenced with a minimum 6-foot high metal pipe fence with woven wire between the posts or an equivalent chain-linked fence. A manual-controlled rolling gate will be located at the access of the site, which will be pad lockable. This may be upgraded to a mechanized system in the future. Only personnel authorized for entry will have access to the sites and will be able to open the gates. Only authorized trucking firms will have access to the site.

Surveillance

The site will be monitored by 24 hour camera surveillance.

Tamper Proof Locks

All gates and other entry points shall be locked when the facility is unattended. The Permittee will provide tamper-proof seals for the master valve on the well; and install locking caps on all valves and connections on holding tanks, unloading racks, and headers.

Manifest System and Chain of Custody for Disposal Water

1. The Permittee will establish and maintain a three-party custody record. This record will be in the form of a database. For every disposal load the Big Bend 1-5 SWD receives, the following information will tracked in a database:
 - Approved Permittees: company name, company address, company telephone number, lease name (the operator will keep track of all production wells that are contained within each lease approved to use the disposal facility)
 - Approved Transporters: company name, company address, company telephone number

- Disposal Fluid: ticket number, truck number, truck driver name, date of pick up, volume produced water picked up, date produced water unloaded at the commercial facility disposal, disposal facility location

A copy the trucking ticket will be scanned and made available with the database upon request of EPA. This database will be kept for a minimum of three years after date of disposal.

2. The Permittee will create a certification by both the transporter and injection facility Permittee that no hazardous waste or non-oil and gas production waste was mixed in with the brine. The form will require the signature of the facility Permittee/owner or authorized employee on an affidavit attesting that the recorded information is correct to the best of his/her knowledge.
3. The Permittee will submit a report to the USEPA and to the generator (other operator using the disposal facility) describing any discrepancies in the composition, transported volumes or place of origin of the brine. These discrepancies may be identified based upon personal observations or information contained on the three-party custody record. This report will be submitted annually to Region 8 UIC Enforcement Program with other required reports.
4. The Permittee will require a Certification from the waste transporting company, in conformance from the appropriate State agency that the transporting company is operating in compliance with specific permit conditions. In many cases the State or Tribal Department of Transportation or equivalent Agency is responsible for registration of transporting companies operating within its borders.
5. The Permittee will insure that each source of brine (defined as produced from a specific lease rather than an individual well) shall be sampled at the time the generator enters into a contractual agreement with the commercial disposal facility. A copy of this data will be maintained by the Permittee. The brine run ticket will track the daily and monthly volumes injected. Water analysis on newly drilled wells may require a grace period (not to exceed 30 business days) prior to being allowed to inject into this subject injection well.